ANADIAN
NERGY
ESEARCH
NSTITUTE

3512 - 33 ST. N.W., Calgary, Alberta — T2L 2A6

Phone (403) 282-1231

WORKING PAPER 83-2

DEVELOPMENT OPTIONS FOR ALBERTA AND SASKATCHEWAN COAL

TRICIA GIBSON

Working papers are distributed by the Canadian Energy Research Institute in limited numbers. They represent the results of work in progress and are made available in this preliminary form both for information and to obtain comments.

CONTENTS

LIST OF FIGURES iv

LIST OF TABLES iv

PREFACE v

CHAPTER 1 OVERVIEW 1

CHAPTER 2 COAL RESERVES 3

CHAPTER 3 SUPPLY AND DEMAND 7

3.1 Historical and Present 7

3.2 Potential and Projected Demand 12
3.2.1 Expansion of Markets 12
3.2.2 Substitution of Coal for Oil and Gas 14
3.2.3 New Technology 15

CHAPTER 4 DEVELOPMENT OPTIONS 19

4.1 What Are They? 19

4.2 Constraints and Considerations 20
4.2.1 Quantity of Coal Resources 20
4.2.2 Ability to Extract 21
4.2.3 Environmental Considerations 25
4.2.4 Technology 25
4.2.5 Markets 27
4.2.6 Transportation 27

CHAPTER 5 EVALUATION OF OPTIONS 33

CHAPTER 6 SUMMARY 37

APPENDIX A: TECHNOLOGY 39

FIGURES

Figure 3.1 Total Coal Production 7

Figure 3.2 Disposition of Coal 9

TABLES

Table 2.1 Interrelations of Rank, Quality and Use 4

Table 3.1 Cost of Fuel Used by Thermal Electric Plants, 1980 Alberta Saskatchewan and Ontario 10

Table 3.2 Principal Coal Producers in 1981 11

Table 3.3 Forecast Demand for Coal; Alberta and Saskatchewan 17

Table 4.1 Development Options 19

Table 4.2 Coal Reserves and Production Alberta and Saskatchewan 21

Table 4.3 Alberta Classification of Lands for Coal Exploration and Development 24

Table 4.4 Comparison of Costs for Various Liquid Fuels 26

Table 4.5 Japanese Imports of Coking and Thermal Coal from Selected Countries, 1981 28

Table 5.1 Data Required by Rank[a] and End-Use 36

Table A.1 Potential Commercial Coal Liquefaction Developments in Canada to the Year 2020[a] 42

PREFACE

The Canadian Energy Research Institute (CERI) is a co-operative research organization sponsored by five parties: Energy, Mines and Resources Canada, the Alberta Department of Energy and Natural Resources, the Private Energy Research Association (composed of corporate and individual members from oil, gas, coal, electrical, nuclear energy and pipeline companies), The University of Calgary and the Ontario Ministry of Energy. The objectives of the Institute are to develop an economic research capability and to conduct studies that will assist industry and government in dealing with energy problems. The research programme of the Institute is developed by a Board of Directors named by the sponsoring organizations. The content of the individual studies is, however, the responsibility of the authors.

In addition to undertaking studies in energy economics funded collectively by the five Institute sponsors, CERI carries out research for clients on a contractual basis.

This working paper is the second of three working papers addressing the issue of development options for coal in various regions of Canada. The other two papers focus on coal in the Maritimes and in British Columbia, respectively.

Once feedback has been received on all three working papers, a study providing a more comprehensive analysis of the development options for Canadian coal reserves will be published.

Chapter 1

OVERVIEW

Over the past fifteen years or so, a rebirth of coal has been witnessed. Once Canada's prime energy source, coal tended towards disuse during the 1950s after the discovery of abundant supplies of oil in western Canada and the conversion to diesel power by the railways. After a decade of decline followed by a decade of stagnation, the coal industry rebounded. Production in Canada increased from 9.7 million tonnes in 1969 to 40.1 million tonnes in 1981 for an average annual increase of 12.6 percent. Real oil price increases which sparked interest in alternative fuel sources played a major role in the industry's revitalization.

Canada is rich in coal resources with major deposits currently being exploited in British Columbia, Alberta, Saskatchewan, and the Maritimes. This paper represents one of three working papers which address development options for Canadian coal. The focus of this paper is on development options for coal in Alberta and Saskatchewan, another addresses the topic as it applies to British Columbia, while the third paper focuses on development options for Maritime coal. This paper does not include specific project evaluations nor does it include detailed technical information. It is intended to provide general information about coal in Alberta and Saskatchewan, and about the prospects for future development of this abundant energy source.

Vast quantities of coal lie in the Plains of Saskatchewan and Alberta and in isolated pockets throughout the Foothills and Mountain regions of the latter. Chapter 2 deals with the quantity and types of coal reserves found in Alberta and Saskatchewan. Supply and demand are examined in Chapter 3, with respect to historical and projected trends. Development options for the provinces' coal are identified in Chapter 4, along with a review of some constraints and

considerations. In Chapter 5 the relative attractiveness of competing development options are evaluated. Finally, a summary of the major findings is presented.

Chapter 2

COAL RESERVES

Almost half of Canada's coal reserves lie in Alberta. Out of an estimated 2.7 billion tonnes of coal which is deemed recoverable, 2.2 billion tonnes are subbituminous rank, 0.3 billion tonnes are low to medium volatile bituminous rank, and 0.2 billion tonnes are high volatile bituminous rank. Minor deposits of semi-anthracite and lignite are also found in the province. Saskatchewan's reserves are estimated at 1.7 billion tonnes of lignite. They represent about 30 percent of Canadian coal reserves.[1]

Coal is a non-homogeneous mineral. It is necessary to examine the properties of coal occurring in the two provinces, noting their differences and suitable uses. Table 2.1 classifies coal by rank, listing general characteristics and potential end uses. Common to all western coal is its low sulphur content, usually less than one percent. Low to medium volatile bituminous coal has a heat value between 25 and 30 gigajoules (GJ)/tonne, high volatile bituminous coal has about 25 GJ/tonne, subbituminous coal ranges from 16 to 22 GJ/tonne and lignite has 16 GJ/tonne on average.[2]

Low to medium volatile bituminous coal, commonly referred to as metallurgical or coking coal, lies in the Mountain region. High volatile bituminous coal, a high grade thermal coal suitable for export, is found mostly in the Foothills region, especially around Hinton, with smaller deposits near Crowsnest Pass and Lethbridge. All of Alberta's subbituminous reserves are found in the Plains extending from the U.S. border north to the Lesser Slave Lake area.

Saskatchewan lignite reserves are, for the most part, confined to four areas close to and parallel to the U.S. border. From east to west, they are Estevan, Willow Bunch, Wood Mountain and Cypress.

TABLE 2.1

INTERRELATIONS OF RANK, QUALITY AND USE

Coal of this rank		Generally has these qualities	and has these potential uses or these characteristics	Depending on qualities such as:
Class	Group			
Anthracitic	All groups	Relatively high calorific value	As a thermal coal	Quantity of ash, sulphur and other deleterious constituent and the extent to which they can be removed or suitably reduced by beneficiation processes; ash fusibility
		Non-agglomerating	Does not coke	
		Low moisture content	Stores and transports well	
		High fixed carbon content	Source of carbon	
Bituminous	All groups	Variably agglomerating	As a blend or directly for making metallurgical coke	Sulphur content and extent to which it can be removed or reduced by beneficiation processes; coal type
		Relatively high calorific value	As a thermal coal	Comments at top of column apply here as well
		Low moisture content	Stores and transports well	
	Hv A, B and C	Fairly high volatile matter content	For gasification or liquefaction	
Sub-bituminous	All groups	Non-agglomerating	Does not coke	
		Moderately high calorific value	As a mine-site thermal coal	Comments at top of column apply here as well
		High moisture content	Does not store or transport well; subject to spontaneous combustion	
		High volatile matter content	For gasification or liquefaction	
Lignitic	All groups	Non-agglomerating	Does not coke	
		Relatively low calorific value	As a mine-site thermal coal	Comments at top of column apply here as well
		High moisture content	Does not store or transport well; subject to spontaneous combustion; may necessitate drying before use	

SOURCE: Energy, Mines and Resources Canada, Report 79-9.

Footnotes

[1]These figures are based on Energy, Mines and Resources Canada's definition of coal reserves and are reported in EMR Report 79-9. Estimates of reserves in Alberta reported by the Alberta Energy Resources and Conservation Board, Report 82-31, are based on a less stringent definition of reserves. The notable difference in the two sets of estimates is exemplified in the following table.

COAL RESERVES IN ALBERTA
(billion tonnes)

Rank	EMR Estimate	ERCB Estimate
Subbituminous	2.2	12.7
Bituminous		
L-m Volatile	0.3	1.7
H Volatile	0.2	1.1
Total	2.7	15.6

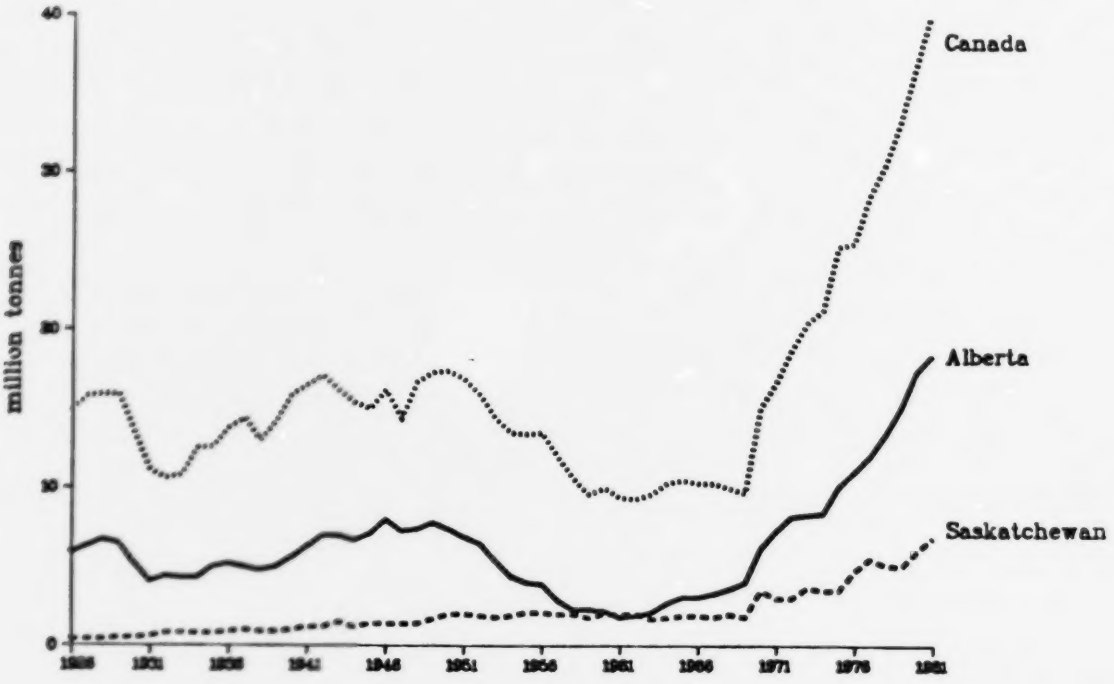
[2]Energy, Mines and Resources Canada, Report 79-9.

Chapter 3

SUPPLY AND DEMAND

3.1 Historical and Present

Prior to the discovery of substantial supplies of oil and natural gas and before railways converted their locomotives to diesel power, coal was the prime source of energy for Canadians. During the 1950s and 1960s, its use fell dramatically (see Figure 3.1).



Source: Statistics Canada, Catalogue No. 26-206.

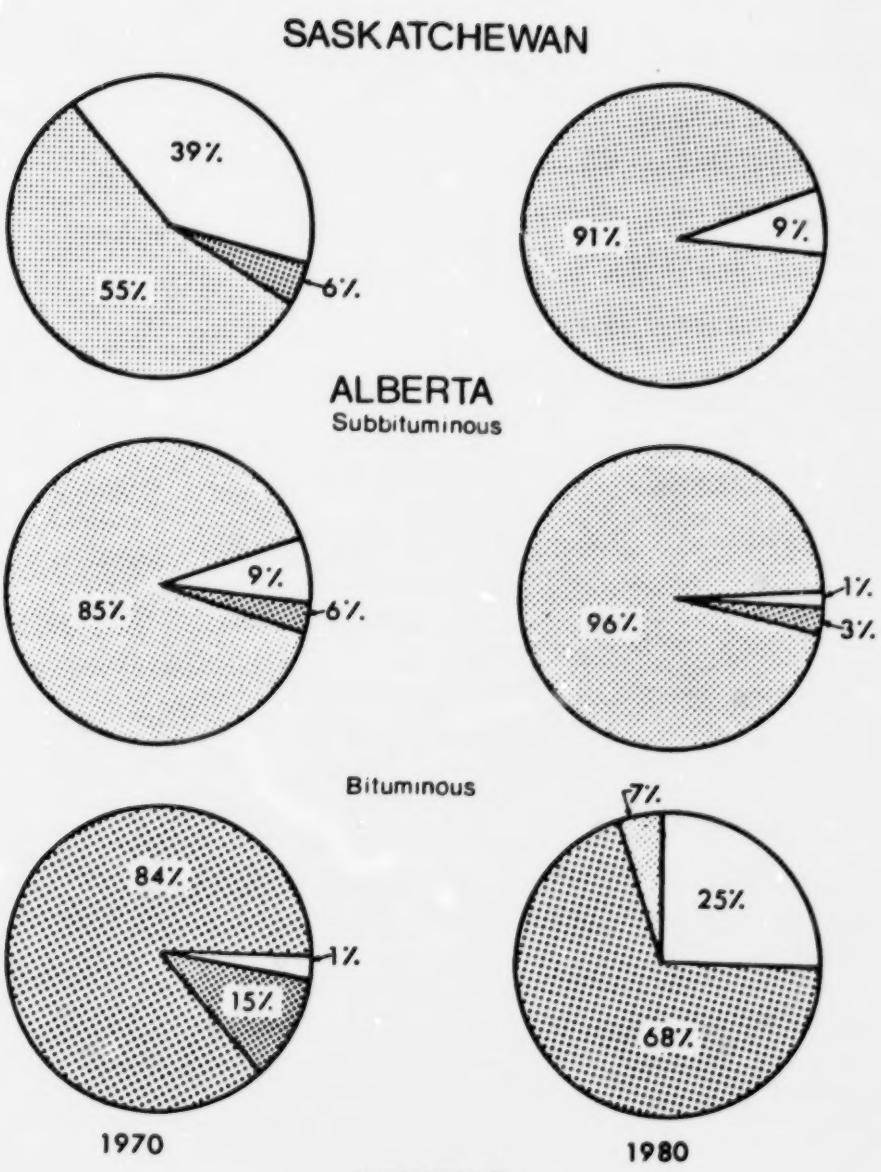
Figure 3.1: Total Coal Production

The pickup in Alberta and Saskatchewan is attributed to growth in coal-fired electricity generating capacity and metallurgical coal export markets. Figure 3.2 shows that over the period 1970 to 1980 the share of Saskatchewan's lignite devoted to generating plants[1] increased from 55 to 91 percent, while Alberta subbituminous coal destined for generating plants rose from 85 percent to 96 percent of total subbituminous production. Due to a sharp increase in the amount of Alberta coal contracted by Ontario Hydro in the late 1970s, the share of bituminous coal destined for extra-provincial markets swelled to 25 percent from a mere one percent over the ten-year period. Although the share of bituminous coal bound for overseas markets subsequently declined, it shouldn't be construed as a weakening in export position. To the contrary, the level of bituminous coal exports jumped from 0.8 million tonnes in 1969 to 2.2 million tonnes a year later, then more than doubled again to reach 4.7 million tonnes in 1980.

Electricity generation is the largest single source of demand for coal in Alberta and Saskatchewan. Considering the price advantage subbituminous and lignitic coals have over alternative fuels, it is not surprising that the utilities rely on them heavily (see Table 3.1). Operations serving minemouth power plants are listed in Table 3.2.

All generating capacity installed in Alberta and Saskatchewan since the quadrupling of world oil prices in 1974 has been coal-fired. In recent years, both provincial governments have issued statements outlining their development policy for coal.[2] Provision of adequate supplies of coal for use in present and future electricity generation has been given high priority.

Most remaining demand for Alberta and Saskatchewan coal is accounted for by export and extra-provincial markets. Initially exports were limited to metallurgical coal with coking coal producers benefiting from expansion of the Japanese steel industry over the past decade. In recent years, however, Alberta's high quality thermal coal has broken into the international market. In 1981, 2.9 million tonnes of metallurgical coal and 1.4 million tonnes of



Source: Statistics Canada, Catalogue No. 26-206

*Includes Industrial Consumers

FIGURE 3.2: DISPOSITION OF COAL

TABLE 3.1

COST OF FUEL USED BY THERMAL ELECTRIC PLANTS, 1980
ALBERTA, SASKATCHEWAN AND ONTARIO
($/KJ)[a]

Fuel	Alberta	Saskatchewan	Ontario
Coal:			
Canadian Bituminous	0.08[b]		2.33
Imported Bituminous			1.71
Subbituminous	0.29	1.06	
Lignite		0.38	
Light Fuel Oil		4.34	3.77
Heavy Fuel Oil		2.91	2.22
Diesel Fuel Oil	4.29	5.22	4.40
Natural Gas	0.93	1.82	2.53

SOURCE: Based on Statistics Canada, Catalogue No. 57-202.

[a]KJ = Kilojoules

[b]This figure is calculated by dividing cost (value) of bituminous coal used by quantity used by thermal electric plants in Alberta. If the value of total provincial bituminous coal production is divided by quantity produced, a higher 'cost' results, $1.20/KJ vs. $0.08/KJ. Since much of the coal supplied to the utilities comes from mining operations owned by the utilities themselves, this cost of bituminous coal, i.e., $0.08/KJ, understates the opportunity cost of the resource.

TABLE 3.2

PRINCIPAL COAL PRODUCERS IN 1981

Company and Mine Location	1981 Raw Coal Production (000 tonnes)	Coal Rank[a]	Chief Markets	Remarks
ALBERTA				
Subbituminous Mines				
Manalta Coal Ltd. Roselyn Mine, Sheerness	69	Sub C	Power generation	Surface
Manalta Coal Ltd. Vesta Mine, Halkirk	1 110	Sub C	Power generation Residential	Surface
Forestburg Collieries Ltd. Diplomat Mine, Forestburg	1 038	Sub C	Power generation Residential	Surface
Manalta Coal Ltd. Whitewood Mine, Wabamun	1 447	Sub A & B	Power generation	Surface
Highvale Mine, Sundance	7 832	Sub C	Power generation	Surface
Bituminous Mines				
Coleman Collieries Ltd. Tent Mountain, Coleman	b		Japan for coke-making	Surface
Cardinal River Coals Ltd. Cardinal River Mine, Hinton	1 500	Mvb	Japan for coke-making	Surface
Luscar Sterco Ltd. Coal Valley Mine, Hinton	4 974	Mvb	Ontario Hydro and West Germany	Surface mine opened in 1976
McIntyre Mines Limited Smoky River Mines, Grand Cache	3 205	Lvb	Japan for coke-making	Surface and underground
SASKATCHEWAN				
Lignite				
Manitoba and Saskatchewan Coal Company (Limited) M & S Mine, Bienfait	1 141	Lig A	Power generation Industrial	Surface
Boundary Dam Mine, Estevan	1 422	Lig A	Power generation	Surface
Manalta Coal Ltd. Klimax Mine, Estevan	738	Lig A	Power generation Industrial	Surface
Manalta Coal Ltd. Utility Mine, Estevan	2 397	Lig A	Power generation	Surface
Saskatchewan Power Corp. Souris Valley Coal Mine, Estevan	302	Lig A	Power generation	Surface
Saskatchewan Power Corp. Poplar River Mine, Coronach	798	Lig A	Power generation	Surface

SOURCE: Energy, Mines and Resources Canada, Canadian Minerals Yearbook, Coal and Coke 1981, advance copy.

[a]Sub = Subbituminous; Lvb = Low volatile bituminous; Mvb = Medium volatile bituminous; Hvb = High volatile bituminous; Lig = Lignite.

[b]Closed in July 1980. Plant being modified to rewash the refuse piles in the Coleman area.

thermal coal were exported to various offshore markets including Japan, Germany, Brazil and Korea.

Ontario Hydro represents Alberta's and Saskatchewan's biggest out-of-province customer in Canada. In the past few years, the utility significantly increased its contracted volumes of western thermal coal in an effort to reduce sulphur type emissions and to lessen dependence on U.S. imports. This was done despite the barrier of high transport costs from western to central Canada. Ontario Hydro has a 15-year contract ending in 1993 for 1.8 million tonnes of bituminous coal per annum from Alberta. About 1.5 million tonnes per annum of Saskatchewan lignite is also contracted by the utility.

3.2 Potential and Projected Demand

Growth in the demand for coal will be derived from three sources:

- expansion of markets;
- increased substitution of coal for oil and natural gas; and
- development of new technology.

3.2.1 Expansion of Markets

As indicated above, the primary existing markets are minemouth power plants, extra-provincial exports of thermal coal and offshore exports of metallurgical and thermal coal.

The Alberta Energy Resources Conservation Board (ERCB) forecasts subbituminous coal requirements for electricty generation to increase from 11.4 million tonnes in 1981 to 20.6 million tonnes in 1990,[3] while Saskatchewan Power Corporation forecasts lignite requirements for generating plants to rise from 5.6 million tonnes to around 7.8 million tonnes over roughly the same period.[4] This represents average annual growth in the order of 6.8 percent and 3.8 percent per annum respectively.

Due to Ontario Hydro's plans to meet future energy requirements by developing nuclear power plants as opposed to expanding its coal-fired generating capacity, demand for Alberta's and Saskatchewan's coal by Ontario Hydro is expected to fall short of what might be expected based on forecasts of growth of economic activity in Ontario. However, there is potential for Saskatchewan to ship an additional 500 thousand tonnes of lignite to Ontario Hydro to fire the Atikokan generating station which is now under construction. Western Canadian coal will continue to be burdened with high transport costs impeding its ability to compete with coal from northeastern U.S. Research on the upgrading and drying of subbituminous and lignitic coals is being conducted which could make their transport more economic in the future.[5]

The outlook for exports of metallurgical coal is clouded at this juncture. The worldwide recession has curtailed steel production and has led to a downward revision in production prospects for the remainder of the decade. Most contracts for Alberta's bituminous coal are with Japanese customers. In recent months, the Japanese have only accepted 80 percent or less of contracted volumes from all of their suppliers. By offering incentives in the form of equity participation, the Japanese have promoted expansion of the number of firms engaged in coal mining. Consequently, the quantity of coal available on the world market has increased and the Japanese have secured leverage. One industry analyst has said "The word 'contract' is not translatable into Japanese...if they can't use the coal, they can't take it."[6] A magnanimous marketing executive of one of Canada's leading coal producers concurred, stating "if they're not producing or selling steel, they can't consume coal, and all they can do is cut back fairly among their various suppliers."[7] By holding an equity position, the Japanese maintain integrity as a partner in a contract. Furthermore, the Japanese contribution to equity may have been responsible for ensuring development of certain Canadian mining projects. The flexibility afforded Japanese buyers can, thus, be viewed as a trade-off for financial risk reduction.

Export contracts are generally long term (10 years or so). Until recently, the price was fixed for the length of the agreement. Contracts negotiated over the past year or two, however, suggest that more frequent price reviews are becoming standard procedure.

The outlook for expansion in the thermal coal export market is generally promising, despite a dampening of the optimism expressed only a year or two ago. Studies released within the past two years suggested that exports of Alberta's high grade thermal coal could reach 5 million tonnes by 1985 and possibly 10 million tonnes by 1990.[8] Indications now are that little more than half of the volumes forcasted in 1981 may actually be realized.[9] Even so, this represents strong growth over the decade of the 1980s. Plans for new coal-fired electricity generating stations in Japan and some Pacific Rim countries account for some of the anticipated increased demand.

Other future sources of demand for coal include the use by in-situ oil sands producers for steam raising and establishment of electricity export markets. Recent postponements of oil sands projects, however, will delay the increased coal requirements projected a few years ago. According to the most recent ERCB estimates, 5 to 7 million tonnes of coal per annum will be needed for in-situ operations around the end of the century.[10] The coal industry would also benefit, indirectly, if export markets were to open up for electricity generated in local coal-fired stations. A scheme to deliver electric power to states on the U.S. western seaboard from Alberta was proposed by an Alberta coal producer in 1982.[11]

3.2.2 Substitution of Coal for Oil and Gas

Increased substitution of coal for oil and gas will stimulate coal demand. Substitution has already occurred to some extent, but there is room for further, more widespread substitution, particularly among industrial users. The ERCB forecasts industrial requirements at 0.4 million tonnes by 1991, up from 0.1 million tonnes in 1981.[12] In Saskatchewan, the Interprovincial Steel Corporation is investigating the use of lignite in a direct reduction process to

form sponge iron from Labrador iron are pellets.[13] If successful, this could result in significant expansion of industrial use of lignite in the province. Conversions of electricity generating plants from oil and gas to coal-fired is costly but may become feasible if the price differential between the fuels widens. If implemented, new methods of using coal, such as coal-oil mixtures which enable coal to be used in oil-fired plants, could increase demand for coal. However, the potential impact of substitution of coal for oil by the utilites in Alberta, Saskatchewan and Ontario is limited; of electricity generated in each province, only 17, 6, and 5 percent, respectively, is fired by oil or gas. The potential is greater in the international market. For example, in Japan, South Korea and Taiwan, 60 percent or more of electricity is generated in oil-fired plants.[14] The push for substitution has waned due to the softening of oil prices, but this situation is not likely to persist over the longer term.

3.2.3 New Technology

Another means whereby new markets could be realized is through the development of new methods of using coal. This might be achieved by either changing the form in which coal is used (eg., solid, liquid, or gas) or by combining it with other substances to obtain a mixture which provides qualities unattainable when the components are used in isolation. The technology is generally available for coal conversion processes such as liquefaction and gasification but, at present, the economics don't justify development on a commercial scale. Recent studies indicate that coal liquefaction entails operations requiring substantial front-end capital outlays with the cost of the final product being higher than, for instance, the cost of synthetic crude oil obtained from oil sands. Gasification, too, involves high costs which are difficult to justify in light of the abundant supply of natural gas readily available in western Canada. Coal conversion on a commercial scale isn't expected to attract serious attention in Alberta and Saskatchewan until at least the 1990s. A more detailed discussion of this topic is presented in the following chapter and in the Appendix.

Table 3.3 presents demand forecasts for Alberta and Saskatchewan coals. In light of developments since the summer of 1982, the forecasts for export demand, in particular, appear to be optimistic. As noted above, thermal coal exports in 1990 may be in the 5 million tonne range rather than 17.6 million tonnes as indicated in the table.

TABLE 3.3

FORECAST DEMAND FOR COAL; ALBERTA AND SASKATCHEWAN
(million tonnes)

		Alberta			Saskatchewan		
Rank	Market	1981	1990	2000	1981	1990	2000
Sub	Electricity Generation	11.4	20.6	21.0			
	Industrial	0.1	0.4	5.8			
Lig	Electricity Generation				5.6	7.8	12.0
	Out of Province				1.2	2.0	3.0
Hvb	Thermal Export	1.4	17.6	23.7			
	Out-of-Province	1.7	1.8	1.8			
L-mvb	Metallurgical Export	2.9	8.5	8.5			

SOURCES: (1) Alberta Energy Resources Conservation Board, Report 82-F and communication with E.R.C.B.; (2) Communication with Saskatchewan Power Corporation and A. Verma, "Trends in Coal Utilization in Saskatchewan," paper presented at 64th C.I.C. Coal Symposium, Halifax, May 31-June 3, 1981.

NOTE: Sub = Subbituminous, Lig = Lignite, Hvb = High volatile bituminous, L-mvb = Low to medium volatile bituminous.

Footnotes

[1]Includes industrial consumers.

[2]See Alberta Department of Energy and Natural Resources, "A Coal Development Policy for Alberta," June 1976; and Saskatchewan Mineral Resources, "Saskatchewan Coal Policy," September 1978.

[3]Alberta Energy Resources Conservation Board, Report 82-F.

[4]Communication with Saskatchewan Power Corporation.

[5]'Beneficiation' or the drying and upgrading of low quality thermal coals is discussed in Chapter 5.

[6]Financial Times, September 20, 1982.

[7]Ibid.

[8]Kai Consulting Inc., "Coal: An Industry Survey and Review of Western Canada's Export Potential, 1985 and 1990," 1982; and Canada Department of Industry, Trade and Commerce, "Survey of World Thermal Coal Demand," September 1981.

[9]See, for example, "Revised Interim Report on the Japanese Market for Imported Coal," Canadian Embassy, Tokyo, May 1982.

[10]Alberta Energy Resources Conservation Board, op. cit.

[11]Financial Post, May 15, 1982.

[12]Alberta Energy Resources Conservation Board, op. cit.

[13]T. Adamcewicz, "Saskatchewan's Coal Future," CIM Bulletin, October 1982, p. 102.

[14]J. Gallagher, "Coal: Global Energy Option for the 1980s," Hydrocarbon Processing, March 1982, p. 72 L.

Chapter 4

DEVELOPMENT OPTIONS

4.1 What Are They?

In view of the large reserves of coal in Alberta and Saskatchewan, the level of resource utilization is mainly determined by the relative prices of alternatives such as crude oil and natural gas and by the levels of economic activity within the provinces and foreign countries in which Canadian coal is consumed. In the short run, at least, coal is demand constrained rather than the more usual opposite. Table 4.1 sets out some development possibilities for bituminous, subbituminous, and lignitic reserves in Alberta and Saskatchewan. As noted earlier, rank can limit potential end use (eg., non-agglomerating subbituminous coal is generally not appropriate for coking).

TABLE 4.1

DEVELOPMENT OPTIONS

End Use	Bituminous		Subbituminous	Lignite
	Low to Medium Volatile	High Volatile		
Electricity Generation:				
- for domestic consumption		X	X	X
- for export		X	X	
Out of Province:				
-thermal		X		
Export:				
- thermal		X		
- metallurgical	X			
Liquefaction		X	X	X
Gasification		X	X	X
Industrial Use		X	X	
In-Situ Oil Sand Recovery			X	

4.2 Constraints and Considerations

The various constraints which may prohibit or limit the extent to which a particular option can be pursued can be covered under six general headings:

- Quantity of Coal Resources
- Ability to Extract
  - economics
  - labour supply
  - capital
  - government policy
- Environmental Considerations
- Technology
- Markets
  - existence of markets - domestic, foreign
  - ability to compete in these markets
- Transportation
  - railway capacity
  - slurry pipelines

4.2.1 Quantity of Coal Resources

Table 4.2 indicates that at 1981 production rates, Alberta's reserves of low to medium volatile coal and high volatile coal could last for about 50 years while reserves of subbituminous coal will extend for around 180 years. In Saskatchewan, reserves of lignite would last close to 250 years at present recovery rates. These are conservative estimates based on Energy, Mines and Resources Canada's definition of recoverable coal reserves.[1] The quantity of coal resources is not expected to represent a constraint to development for decades or centuries to come.

TABLE 4.2

COAL RESERVES AND PRODUCTION,
ALBERTA AND SASKATCHEWAN

Rank	Reserves (million tonnes)	1981 Production (million tonnes)	Reserves ÷ Production = Years Supply (years)
Alberta			
Bituminous:			
- L-m Volatile	290	5	58
- H Volatile	240	5	48
Subbituminous:	2182	12	182
Saskatchewan			
- Lignite	1720	7	246

SOURCES: Energy, Mines and Resources Canada, Report 79-9; ERCB, Report 82-29; Saskatchewan Energy and Mines.

4.2.2 Ability to Extract

(i) Economics

Cost estimates for surface mining operations in the Plains are in the range of $10.00 to $15.00 per tonne (in 1982 Cdn. $). Coal mined in the Foothills and Mountain regions costs in the order of $25.00 to $40.00 per tonne of raw coal (in 1982 Cdn. $), with costs for underground mining operations tending towards the upper end of the range.[2] However, it is hazardous to make generalizations about mining costs since every site represents a unique set of circumstances. Wide variations in cost can occur based on factors such as overburden ratio, seam thickness and mining method. However, it might be useful to point out some factors which will contribute to higher future mining costs in general. As the high quality and most accessible reserves are exhausted, producers will be compelled to exploit thinner, lower quality reserves in more rugged and remote locations. Costs will rise as infrastructure becomes a larger cost component, overburden ratios become higher, and deeper deposits necessitate

implementing underground techniques. If Alberta's most economically acessible deposits are depleted at a fast rate relative to other world coal suppliers, the coals' competitive position could be weakened.

(ii) Labour Supply

Some concern has been expressed regarding the availability of skilled manpower to meet future mining requirements. In 1981, manpower planning agreements between the federal government and both the Coal Association of Canada and the Mining Association of Canada were instituted to establish a cooperative framework that would lead to a survey and projection of employment requirements in the coal industry and provide training in high demand occupations.[3] Labour shortages aren't likely to appear in the immediate future due to the presently high unemployment situation but there could be a problem over the longer term, especially if several large resource related projects were to proceed simultaneously in western Canada.

(iii) Capital

Development of a natural resource can involve large capital expenditures, especially if infrastructure and transport systems need to be put in place. If some of the megaprojects envisioned for the 1980s are revived, competition for capital funds could impede development.[4]

(iv) Government Policy

Governments can influence the development options available for coal in several ways.

Firstly, government approval must be granted in both Alberta and Saskatchewan before exploration or development activities can proceed. Failure to comply with elements of government coal policies by not providing coal supply and demand information, conducting environmental impact studies, maximizing local manpower or ensuring maximum practical recovery of coal, for example, would mean denial of the lease or licence. In Alberta, coal projects must meet the requirements set out in some twenty five pieces of legislation

before proceeding, thus making it a costly process for producers.[5]

Secondly, provincial governments can dictate the use of provincial lands. Coal mining activity is strictly prohibited in certain areas of Alberta. The province's coal policy sets out 4 categories of land as shown in Table 4.3. Category 1 includes parks, major lakes and rivers, and settled urban areas. The second category generally refers to areas in the Rocky Mountains and Foothills where infrastructure is absent or where preferred land or resource use remains to be determined. Much of the province's bituminous resources lie in these two categories. Category 3 covers most forested land in the north and eastern portions of the Mountain and Foothills regions. Although these lands are less environmentally sensitive than those in Categories 1 and 2, assurances are required that agricultural lands used for mining will be reclaimed to a level of productivity equal to or greater than that which existed prior to mining. The last category encompasses all lands not included in the other three categories. No similar categorization of lands exists in Saskatchewan.

TABLE 4.3

ALBERTA CLASSIFICATION OF LANDS FOR
COAL EXPLORATION AND DEVELOPMENT

Category	Exploration	Development
1	None permitted	None permitted
2	Limited exploration permitted under strict control	Restricted development, underground or in-situ only
3	Exploration permitted under normal approval procedures	Restricted development
4	Exploration permitted under normal approval procedures	Development permitted under normal approval procedures

SOURCE: Based on Alberta Department of Energy and Natural Resources, A Coal Development Policy for Alberta, June 1976.

Thirdly, governments can provide both incentives and disincentives to mine and process coal via the tax system. Royalties are levied by governments in both provinces. In Alberta, royalty rates follow a sliding scale from a minimum of 5 percent of gross revenues on small or marginally economic operations to about 33 percent on more profitable operations. In addition, a 36-month 'phase-in' period for new commerial operations is allowed.[6] A royalty of 15 percent of minehead value is levied in Saskatchewan.[7] Coal contained in freehold properties in both provinces is subject to property taxation. An interesting question is posed in the event of a coal liquefaction plant. Would such a facility be subject to coal royalties or oil royalties, which would, presumably, be higher?

In general, government policies affecting coal development and production should be seen within the overall economic framework in which priorities for energy development are set with incentives and disincentives reflecting the

government's desire for increased or decreased coal development.

4.2.3 Environmental Considerations

In Alberta and Saskatchewan, environmental concerns such as acid rain retain a relatively low profile due to the coal's generally low sulphur content. Awareness of the negative effects of coal's use on the environment is increasing, however, and more stringent regulations may be put in place in the future which could impede development of the coal resources.

4.2.4 Technology

The realization that supplies of conventional oil and natural gas are limited has generated renewed interest in coal conversion. In various countries of the world, liquefaction and gasification were widely employed in the first half of this century. But following the Second World War, relatively cheaper oil and gas supplanted the coal-derived products. Due to sharp increases in the prices of fossil fuels over the past eight years, however, coal conversion technologies are being revived and improved. Whether these technologies open new markets and hence increase demand for coal will depend on two factors:

- achieving technical success of the process at both the pilot and commercial stages; and
- existence of an economic environment in which coal-derived products are competitive.

Liquefaction, gasification, co-processing of coal and bitumen, coal-oil mixtures and integrated coal gasification combined cycle (IGCC) are some of the technologies being researched in Canada which may be appropriate for Alberta and Saskatchewan coals. (See the Appendix for a more detailed discussion.) Thus far, Canadian research is adaptive, rather than innovative, with emphasis on modifying existing technology to domestic coals and market demand. Canada's research programme lags behind those of other countries, with government expenditures (in 1982 U.S. $) on coal R and D in 1981 at

$7.2 million compared to $419.9 million in the United States, $88.3 million in Germany and $44.3 million in the United Kingdom.[8]

Increased demand for coal related to coal conversion is not anticipated in any quantifiable way. It will likely be at least 10 to 20 years before any commercial operations come on stream in Canada. Cost estimates for various liquid fuels, given in Table 4.4, show that coal-derived liquids are not competitive with ones from conventional sources. Drastic changes in relative prices of fossil fuels could, however, hasten development and implementation of some of the new technologies. A commercial liquefaction project could become a reality sooner than expected if it were financed by foreign investors. A country possessing neither oil nor coal resources may be willing to undertake development of a coal liquefaction facility in another country such as Canada.[9] Due to large reserves of natural gas in Alberta, gasification of that province's coal may be even further from the commercial stage.

TABLE 4.4

COMPARISON OF COSTS FOR VARIOUS LIQUID FUELS
(1982$)

Fuel	$/GJ
Conventional Crude (Blended Price)	5.50
Synthetic Crude (New Oil Reference Price)	7.08
Coal	
- Liquefacation	9.80-13.07
- Partial Liquefaction	10.06[a]

SOURCE: Based on Corpus, "Energy Pricing News "October 1982; Z. Kolisnyk, "Coal Pyrolysis - The Third Alternative," presentation to the 33rd Canadian Coal Conference, Regina, September 20 - 22, 1981; and Canadian Energy Research Institute estimates.

[a]Escalated by 12 percent over the period 1981 to 1982.

4.2.5 Markets

Clearly, coal should not be developed for uses for which there is unlikely to be a market. As indicated above, electric utilities will continue to represent the largest source of demand for coal in both provinces. Refinement of coal-oil mixtures and of the IGCC process could also increase the extent to which coal is used by the utilities.

Exports of bituminous coal constitute the next largest share of total coal shipments. Despite the present depressed state of foreign markets, particularly for metallurgical coal, the outlook for world coal trade is generally optimistic. With Pacific Rim countries pursuing energy programmes aimed at reducing dependence on oil and gas, the prospects for increased deliveries of thermal coal look good. In order for Canada to maintain and expand its export markets, Canadian coals must be competitively priced. Producers of Alberta bituminous coal are placed at a disadvantage since hundreds of miles of rugged terrain separate the coal mines from coastal ports. Labour costs, which are higher for Canadian producers than, for example, South African producers, also make it more difficult for Canadian producers to compete successfully for the Japanese and other markets. Despite the difficulties, Canadian bituminous coal is competitively priced, in general, with coal from Australia and South Africa (see Table 4.5).

In the long term, new markets may open up when technologies such as coal liquefaction are implemented on a commercial scale.

4.2.6 Transportation

(i) Railway Capacity

One further concern is the ability of the railways to handle increased freight volumes over the next decade. The statutory Crowsnest Pass freight rate allows western farmers to ship grain at rates which only cover about one fifth of the costs while other commodities, such as coal, are subject to higher rates set by the railways. Consequently, railways lack sufficient financial resources to maintain, improve and

TABLE 4.5

JAPANESE IMPORTS OF COKING AND THERMAL COAL FROM SELECTED COUNTRIES, 1981

Supplier	Coking		Thermal	
	thousand tonnes	U.S.$/ tonne[a]	thousand tonnes	U.S.$/ tonne[a]
Canada	9,554	64.69	1,140	62.95
United States	21,571	83.50	2,119	73.22
Australia	29,128	65.70	5,676	65.70
South Africa	2,962	64.14	1,263	55.41
Average Price of Total Imports		71.32		65.69

SOURCE: Based on Coal Manual, 1982 Edition, The Tex Reporter Ltd.

[a]Average C.I.F. value per wet tonne. Converted from yen to U.S. dollars using exchange rate of U.S. $1.00 = Y219.94.

expand facilities and services in western Canada. Complaints of inadequate service are already being heard and preservation of artificially low grain rates would further aggravate the situation. For this and other reasons, the federal government is taking action to abolish the Crow Rate. Throughout the spring of 1982, Clay Gilson, appointed to the Federal Representatives, conferred with the railways and farm organizations, "to identify and enhance the consensus among agricultural organizations on a number of issues related to the transport of grain" and to make specific proposals for financing future grain movement.[10] Legislation is expected to be passed early in 1983 which will raise grain rates to reflect actual transport costs, thereby increasing revenues for railways. Bituminous coal producers in Alberta have a decided interest in resolution of the grain rate issue since rail provides a vital link to western coastal ports and export markets.

(ii) Slurry Pipelines

Coal slurry pipelines are currently being investigated as an alternative mode of transporting coal.[11] The Slurry Pipeline Development Centre in Saskatchewan is devoted to the study of transportation of solid materials such as coal through pipelines.[12] Two projects sponsored by the Alberta government are at the economic feasibility stage. In late 1981, Fluor Canada Ltd., released results of a study[13] on a coal/water slurry pipeline to transport thermal coal from Alberta to west coast ports. It was concluded that a project of this type was not feasible due to high transport costs relative to rail and due to market preference for dry coal. Coal/methanol slurry pipelines have also attracted interest.[14] Although eliminating the dewatering problem, utilizing methanol as the transport agent is more costly than utilizing water. Because railways from Alberta to coastal ports are already in place, it will be years and perhaps decades before coal slurries become an economically attractive transport alternative for western Canadian coals. Short slurry pipelines, however, which would be suitable for supplying coal gasification and steam plants, are used successfully in many parts of the world and it is possible that they could be in use in Canada by the 1990s.

Footnotes

[1]Energy, Mines and Resources Canada defines recoverable coal reserves as "that...(coal)...that could be recovered as run-of-mine coal with current technology and at current market prices. The coal deposit must be legally open to mining, and the necessary infrastructure must be in place or could be amortized through coal sales." (EMR, Report 79-9).

[2]Estimates of coal mining costs are also found in Canada West Foundation, Western Canada's Coal: The Sleeping Giant, November 1980 and Report of the World Coal Study, Coal: Bridge to the Future, 1980.

[3]Coal Miner, May 1981, p. 67.

[4]An interesting discussion, addressing this topic, is found in J. Dawson's, Financing Canadian Energy Resource Development, (Calgary: Canadian Energy Research Institute), Study No. 13, December 1981.

[5]Some examples are The Coal Conservation Act and Regulations, The Clean Water Act and Regulations and The Public Highways Development Act and Regulations. See ERCB, Guide G-2, How to Apply For Government Approval of Coal Projects in Alberta, August 1981.

[6]Alberta Department of Energy and Natural Resources, "A Coal Development Policy for Alberta," June 1976, p. 10.

[7]Saskatchewan Mineral Resources, "Saskatchewan Coal Policy," September 1978, p. 10.

[8]International Energy Agency, OECD, Coal Liquefaction: A Technology Review, 1982.

[9]J. Walsh, "Thinking about Coal," a general lecture prepared for the Imperial Oil lecture series at the University of Western Ontario, November 8 - 10, 1982.

[10]See J.C. Gilson, "Western Grain Transportation: Report on Consultations and Recommendations," June 1982.

[11]See M. Skubnik and B. Whalley, "A Consideration of Coal Slurry Transportation for Canada," Canmet Report No. ERP/ERL 81 - 126 (OP), February 1981 for an overview of the topic. A useful list of references is included.

[12]See W. Husband, et. al., "Slurry Pipeline Development Centre at Saskatoon," presentation at CIM Second Technical Conference on Western Canadian Coals, June 1982.

[13]Prepared for Alberta Department of Energy and Natural Resources and Department of Economic Development by Fluor Canada Ltd., "Coal Slurry Pipeline Feasibility Study 1981," November 1981.

[14]A preliminary feasibility study is currently being conducted by a consortium led by Chieftan Development Ltd.

Chapter 5

EVALUATION OF OPTIONS

Having specified some development options available for Alberta's and Saskatchewan's coal reserves, an evaluation based on both economic and non-economic criteria is in order.

- Coal in a gaseous or liquid state is more valuable than in its primary state. At this time, coal-derived liquids and gases are not competitive with those derived from conventional sources. In the long term, however, coal conversion may be the most beneficial use of the resource. The following statements concur with this view. Former West German Chancellor Helmut Schmidt, in his address to the World Energy Conference in 1980, stated that, "in 10 to 20 years the world is going to realize that coal is too valuable to be burned... In the long run, petro-chemistry is going to have to be replaced by the chemistry of coal." In the same vein, R. Moncur, past president of Saskatchewan Power Corporation, told delegates at the 33rd Canadian Coal Conference in 1981 that, "the optimum use of our (Saskatchewan's) lignite is not thermal; the value of lignite-derived hydrocarbons is greater than the value of lignite-generated electricity."

- The value of coal generally increases according to the degree to which it has been beneficiated. This is especially pertinent for subbituminous coal. Since this low quality thermal coal represents a large portion of total coal reserves, ascertaining optimum utilization is of utmost interest. Transport costs and development of technologies which minimize cost will be the factors which determine whether it is feasible to upgrade these coals for outside markets by dewatering them. Since it is not yet economically feasible to beneficiate subbituminous coals for, say, the Ontario market, this represents an option in the long term only.

- Metallurgical and high grade thermal coals are demanded in the international market. For the purpose of increasing and diversifying the

market, bituminuous coals should be largely reserved for foreign markets.

- Because of the price advantage domestic coal enjoys over alternative fuels for use by electricity generating plants, adequate supplies should be ensured for minemouth power plant use.

- Development of coal reserves to yield maximum benefits to the people of Alberta and Saskatchewan is a policy which has been adopted by the respective provincial governments. This means environmental, employment, and security of supply considerations, as well as economic or financial ones, will determine the shape of future development.

Ranking the options by quantitative methods requires compilation of detailed cost data and price forecasts. Financial analysis is then used to determine the relative attractiveness of the various projects.

A major problem is compiling a representative set of mine-specific cost data. As noted in Chapter 4.2.2 (i), each coal mine represents a unique set of circumstances with an attendant unique set of costs. Cost can vary widely, not only between mines extracting different ranks of coal, but also between mines extracting the same rank but which are located in different geographic areas or employ different mining methods. It is hazardous to make generalizations about mining costs since any analysis based on them would necessarily involve a large degree of error. In addition, the competition which exists among suppliers makes this type of information strongly proprietary in nature.

Ranking also requires tabulation of beneficiation costs, where applicable. Coal utilized by minemouth power plants, such as subbituminous and lignitic ranks, is often used in its raw form (i.e., not cleaned), although it is pulverized prior to use. On the other hand, metallurgical and high grade thermal coals destined for outside markets, are usually cleaned and processed to market specifications prior to shipment.

Transportation costs, whether to a plant for further processing or to a port or final destination, must be accounted for.

If further stages of processing are involved, such as conversion, associated costs must also be taken into consideration. Since much of the technology has not reached the commercial stage, caution must be exercised in not placing undue confidence in cost estimates.

A quantitative approach appears to be most appropriate for selective analysis; that is, for evaluation of alternatives for the development of a particular coal deposit. Table 5.1 sets out a framework within which such analysis could be conducted.

TABLE 5.1

DATA REQUIRED BY RANK[a] AND END-USE

Development Option / Cost Data	Minemouth Power Plant	Out-of-Province	Export; Thermal[c]	Export; Metallurgical	Conversion
Mining:					
Surface	Sub;Lig	Hvb	Hvb;Sub;Lig	L-mvb	Sub;Lig;Hvb
Underground				L-mvb	
Beneficiation	Sub;Lig	Hvb	Hvb;Sub;Lig	L-mvb	
Transportation		Hvb	Hvb;Sub;Lig	L-mvb	Sub;Lig;Hvb
Further Processing	b				Sub;Lig;Hvb

[a]Sub = Subbituminous, Lig = Lignite, Hvb = High volatile bituminous, L-mvb = Low to medium volative bituminous.

[b]Could include subbituminous and lignite for case of COM or IGCC.

[c]Inclusion of subbituminous and lignite represents the case where domestically generated electricity is exported.

Chapter 6

SUMMARY

After a period of decline in the 1950s and 1960s, coal is again receiving serious attention as an important natural resource. The provinces of Alberta and Saskatchewan have been blessed with abundant supplies which should last for decades and centuries to come. Nevertheless, it must be ensured that development of the resource ensues careful planning, taking economic, social and environmental factors into consideration.

In this paper, long term development options available for Alberta's and Saskatchewan's coals have been examined. The major choices for subbituminous coal and lignite are use by minemouth power plants, use by out-of-province generating plants, and conversion. Through time, as technologies become more refined and cost effective, and if the gap between the prices of coal and oil widens, conversion will likely represent the most valuable application. Demand for coal-derived liquid fuels is seen in the long term only (i.e., not before the 1990s or 2000). Competition for the best coal deposits, capital funds and labour, in addition to government policy, will determine the direction development takes.

High volatile bituminous coal's most appropriate use takes advantage of its high thermal content. Since lower grade thermal coals can be substituted locally, superior grades should be reserved for outside markets. This rank is also suitable for conversion, but, due to the small quantity of reserves relative to those of lower grade thermal coals and since the opportunity cost associated with bituminous coal is higher, research in Canada should focus on adapting conversion technologies to subbituminous and lignitic coals.

Low and medium volatile bituminous coals' most appropriate use are for coking. Since they represent the ranks most suitable for this purpose, supplies should be reserved for metallurgical markets.

APPENDIX A

TECHNOLOGY

APPENDIX A

TECHNOLOGY

Direct, indirect and partial liquefaction processes are being researched and tested in various countries around the world, including Canada.

Preliminary assessment of the direct liquefaction of Alberta Plains coal is promising.[1] Advantages of this process, compared to other liquefaction processes, include lower investment costs, higher liquid yields and higher thermal efficiencies. A commercial hydroliquefaction plant could require a large amount of coal. For example, in Alberta, a plant with a capacity of 140,000 barrels per day (comparable to output of the cancelled Alsands oil sands plant or Cold Lake heavy oil plant) would require about 23 million tonnes of coal per annum, or more than total production of coal in Alberta for 1981.[2]

Indirect liquefaction or synthesis involves two stages of processing--gasification followed by liquefaction. Although less attractive in several respects, the indirect route produces a wide variety of liquid products and allows a wider range of coals to be utilized. The South Africans have successfully applied this process on a commercial scale in their Sasol operations. However, this process is not expected to be particularly suitable for Plains coals.[3]

Partial liquefaction or pyrolysis is a process whereby heat is applied to coal to produce liquids, gases and char. The char is subsequently used for direct combustion. Possibilities for implementation of this process by electric utilities are hopeful. According to one source, industrial interests are looking into the possibility of establishing such a plant to provide baseload electric power for export and liquids for local use or export.[4]

Another technology for deriving liquids from coal, which is receiving serious attention, is the co-processing of coal and bitumen. Evidence suggests the combination enhances

the yield from both feedstocks.[5] The possiblities are especially promising where deposits of heavy oil and coal lie side by side.

Table A.1 presents potential commercial liquefaction developments in Canada to the year 2020. With oil sands and heavy oil deposits , the timing and introduction of coal liquefaction will be a function of the cost of coal liquids vis-a-vis the cost of synthetic crude oil, unless overriding policy factors come into play.

Large reserves of natural gas in Alberta preclude gasification of that province's coal on a commercial scale for the next 10 to 20 years. The possibilities in Saskatchewan, though, may not be as remote. In the fall of 1981, R. Moncur, then president of Saskatchewan Power Corporation, suggested that a medium BTU coal gasification plant requiring 7 million tonnes of coal per annum (an amount roughly equal to total 1981 production) might be feasible in the early 1990s.[6]

Even though it is unlikely to become commercially feasible before the end of the century, in-situ gasification will continue to attract a high degree of research activity. Underground coal gasification may be particularly appropriate for Alberta's bituminous coal reserves which are too deep, thin or geologically disturbed to be mined efficiently using conventional methods.[7]

Other technologies being investigated are fluidized bed techniques, coal-oil mixtures (COM) and integrated coal gasification combined cycle (IGCC) processes. Fluidized bed combustion, an alternative to installing flue gas scrubbers to reduce sulphur oxide emissions, has the additional feature of allowing coal with high ash content to be burned, which explains Saskatchewan Power Corporation's interest in the technique. The Alberta Research Council plans to undertake research in fluidized bed technology because of its application in liquefaction processes. Indications are that costs can be reduced and thermal efficiency increased through the use of this technique.[8]

TABLE A.1

POTENTIAL COMMERCIAL COAL LIQUEFACTION DEVELOPMENTS IN CANADA TO THE YEAR 2020[a]

Plant Location	Coal Rank	Technology	Production TJ/d (t.o.e./d)[b]	Cumulative Total Production TJ/d (t.o.e./d)
Developments by 1990				
British Columbia (Hat Creek)	lignite/ subbituminous	synthesis (Sasol or Mobil)	367 (8 340)	
Alberta	subbituminous	flash pyrolysis	184 (4 170)	
Ontario (Onakawana)	lignite	methanol synthesis	43 (970)	
Nova Scotia	high-volatile bituminous	co-processing with refinery resids	153 (3 480)	
Alberta or Saskatchewan	lignite or subbituminous	co-processing with heavy oil	184 (4 170)	
Alberta or British Columbia	subbituminous or bituminous	hydroliquefaction	367 (8 340)	
Nova Scotia	high-volatile bituminous	flash pyrolysis	55 (1 250)	
Cumulative total by 1990				1 353 (30 780)
Incremental developments by 2000				
British Columbia	bituminous	hydroliquefaction	367 (8 340)	
Alberta	subbituminous or bituminous	hydroliquefaction	367 (8 340)	
Alberta	subbituminous	pyrolysis	184 (4 170)	
Nova Scotia	high-volatile bituminous	pyrolysis	92 (2 090)	
Western Canada	lignite or bituminous	co-processing with heavy oil	1 220 (27 700)	
Nova Scotia	high-volatile bituminous	co-processing	153 (3 480)	
Cumulative total by 2000				3 735 (84 970)
Speculative cumulative total by 2020				6 120+(139 000+)

SOURCE: G. Taylor, et. al., "Potential Coal Liquefaction Developments in Canada to the Year 2020".

[a]Although any one of the developments might stand a reasonable chance of going ahead, it is highly unlikely that all will. The cumulative totals therfore represent maximum production scenarios.

[b]t.o.e./d = tonnes of oil equivalent per day.

COM allow coal to be used in oil-fired installations. The potential for COM in Alberta and Saskatchewan is small since only a small share of electricity generating plants are oil-fired and new oil-fired capacity is not likely to be put in place.

Saskatchewan Power Corporation is seriously considering the possibilities for IGCC for electric power generation. Although the technology is not yet fully developed, evidence suggests this type of system could offer increased thermal efficiency (about 10 percent) and lower emissions.[9]

Indications are that coal conversion technologies would require large quantities of coal. However, the provinces are endowed with sufficient resources. For instance, a recent ERCB report states that "provincial coal resources are adequate to support any additional demand by foreseeable coal liquefaction operations."[10]

Footnotes

[1]R. McDonald, "Coal Conversion in Alberta," a paper presented at 33rd Canadian Coal Conference, Regina, September 20-22, 1981, p. 5.

[2]R. Gregory, et. al., "Coal Liquefaction--A Viable Energy Production Method, a paper presented at 94th E.I.C. Annual Cong., Calgary, April 23-25, 1980, cited in Canada West Foundation, "Western Canada's Coal: The Sleeping Giant," November 1980, p. 102.

[3]R. McDonald, op. cit., p. 4.

[4]G. Taylor, et. al., "Potential Coal Liquefaction Developments in Canada to the Year 2020," in Coal Liquefaction Task Force, Conservation Commission, World Energy Conference, London, England, 1982. Also see Z. Kolisnyk and R. Grant, "Coal Pyrolysis - The Third Alternative," presentation to 33rd Canadian Coal Conference, Regina, September 20-22, 1981 for a discussion of pyrolysis.

[5]Ibid.

[6]R. Moncur, "Opportunities for Lignite Development in Saskatchewan," address to 33rd Canadian Coal Conference, Regina, September 21, 1981.

[7]Canada West Foundation, Western Canada's Coal: The Sleeping Giant, November 1980.

[8]M. du Plessis, "Coal Conversion Research Program at the Alberta Research Council," Journal of Canadian Petroleum Technology, July-August 1982, p. 87.

[9]For example, see "Coal Gasification for Electric Power Generation," in Science, March 1982.

[10]Alberta Energy Resources Conservation Board, "Energy Requirements in Alberta 1981 to 2000", Report 82 - F, p. 136.

CANADIAN ENERGY RESEARCH INSTITUTE

PUBLICATIONS

Studies

No. 1 The Availability of Capital to Fund the Development of Canadian Energy Supplies. J. R. Downs. November 1977 (Price $3.00, 109 pages) ISBN 0-920522-00-9.

No. 2 The Industrial Demand for Oil and Gas in Ontario. DataMetrics Limited. March 1978 (Price $3.00, 119 pages) ISBN 0-920522-01-7.

No. 3 The Effects of Rising Energy Costs on Canadian Industry. Anthony P. Ellison. April 1979 (Price $3.00, 62 pages) ISBN 0-920522-02-5.

No. 4 Potential Markets for Thermal Coal in Canada, 1978-2000: Summary and Conclusions. Canadian Resourcecon Limited. June 1979 (Price $3.00, 27 pages) ISBN 0-920522-03-3.

No. 5 Energy in Canada: Review and Outlook to 1995. W. Brent Friedenberg. July 1979 (Price $10.00, 140 pages) ISBN 0-920522-04-1.

No. 6 Energy Policy and the Balance of Payments: An Outline of the Issues. T. L. Powrie. July 1979 (Price $3.00, 61 pages) ISBN 0-920522-05-X.

No. 7 Oil and Gas Finding Costs. Russell S. Uhler. September 1979 (Price $3.00, 75 pages) ISBN 0-920522-06-8.

No. 8 Energy Use in Canada in Comparison With Other Countries. Z. Charles Slagorsky. October 1979 (Price $3.00, 91 pages) ISBN 0-920522-07-6.

No. 9 Enhanced Oil Recovery Potential in Canada. J. Philip Prince. March 1980 (Price $10.00, 332 pages) ISBN 0-920522-09-2.

Conclusions and Policy Implications from Enhanced Oil Recovery Potential in Canada, Study No. 9. J. Philip Prince. March 1980 (Price $3.00, 32 pages) ISBN 0-920522-10-6.

No. 10 The Impact of Rate Structure Change on Electricity Demand: A Case Study of Calgary Power Limited. Gerard J. Protti and Robert N. McRae. April 1980 (Price $10.00, 182 pages) ISBN 0-920522-11-4.

Overview and Summary from The Impact of Rate Structure Change on Electricity Demand: A Case Study of Calgary Power Limited. Gerard J. Protti and Robert N. McRae. April 1980 (Price $3.00, 14 pages) ISBN 0-920522-12-2.

No. 11 The Impact of a Sharp Oil Price Increase. G. E. Angevine. June 1980 (Price $10.00, 122 pages) ISBN 0-920522-13-0.

No. 12 Benefits and Costs of Oil Self-Sufficiency in Canada. J. A. Dawson and Z. C. Slagorsky. February 1981 (Price $10.00, 97 pages) ISBN 0-920522-15-7.

No. 13 Financing Canadian Energy Resource Development. J. A. Dawson. December 1981 (Price $10.00, 68 pages) ISBN 0-920522-17-3.

No. 14 Impacts of Canada's Uranium Mining Industry. Marvin Shaffer and Associates Ltd. May 1982 (Price $10.00, 87 pages) ISBN 0-920522-20-3.

No. 15 Coal and Nuclear Electricity Fuels: A Regional Analysis. Farhood Rahnama. June 1982 (Price $10.00, 81 pages) ISBN 0-920522-21-1.

No. 16 Alternative Transportation Fuels in Canada. Z. Charles Slagorsky. July 1982 (Price $10.00, 112 pages) ISBN 0-920522-23-8.

No. 17 Energy and Regional Investment in Canada. Gordon W. Douglas and Ellen F. Battle. March 1983 (Price $20.00, 114 pages) ISBN 0-920522-28-9.

No. 18 Household Energy Savings: Options for the Future. Brian D. Sumner and Barbara E. Green. March 1983 (Price $20.00, 194 pages) ISBN 0-920522-27-0.

Client Research Reports

81-1 Models for Energy Policy Analysis: A Survey. Kenneth D. Foat, Gerard J. Protti and Gordon W. Douglas. July 1981 (Price $10.00, 121 pages) ISBN 0-920522-16-5.

82-1 The Economics of Improved Energy Efficiency in New Calgary Housing. Barbara E. Green. March 1982 (Price $10.00, 55 pages) ISBN 0-920522-18-1.

82-2 Interregional Economic Impacts of the Alberta Alsands Project. Gordon W. Douglas and J. A. MacMillan. September 1982 (Price $15.00, 78 pages) ISBN 0-920522-24-6.

Working Papers

78-1 Drilling and Field Construction Costs in the Canadian Petroleum Industry. Gordon M. Engbloom, Confer Consulting Limited. January 1978 (Price $3.00, 83 pages).

78-2 Some Supply Price Estimates for Synthetic Crude Oil in Canada. Z. Charles Slagorsky. April 1978 (Price $3.00, 42 pages).

78-3 Past and Future Energy Costs in the Canadian Economy. Anthony P. Ellison. April 1978 (Price $5.00, 136 pages).

78-4 Canadian Electric Utility Industry Costs, 1960-1990. Gerard J. Protti. May 1978 (Price $10.00, 218 pages).

78-5 Enhanced Oil Recovery Potential in Canada - A Methodological Preview. J. Philip Prince. June 1978 (Price $10.00, 184 pages).

78-6 Regional Energy and Production Data for Canadian Manufacturing Industries: 1962-74. Robert N. McRae and Alan R. Webster. July 1978 (Price $5.00, 106 pages).

78-7 Regional Demand for Energy by Canadian Manufacturing Industries. Robert N. McRae. October 1978 (Price $5.00, 132 pages).

79-1 An Input-Output Analysis of the Effects of Rising Energy Costs on Canadian Industries. Anthony P. Ellison. April 1979 (Price $10.00, 246 pages).

79-2 Potential Markets for Thermal Coal in Canada, 1978-2000. Canadian Resourcecon Limited. June 1979 (Price $15.00, 321 pages).

79-3 Inter-City Comparisons of Canadian Household Energy Costs. Darcy-Gail Ackerman. June 1979 (Price $3.00, 77 pages).

80-1 Government Incentives in Canada's Petroleum Industry. W. B. Friedenberg, Z. C. Slagorsky, and A. J. Walsh. March 1980 (Price $3.00, 43 pages).

80-2 A Regionalized Electricity Model: Preliminary Analyses. Kenneth D. Foat and Gerard J. Protti. April 1980 (Price $3.00, 61 pages).

80-3 Alternative Future Supplies of Oil in Canada and Their Costs. Z. Charles Slagorsky. May 1980 (Price $3.00, 36 pages).

80-4 Prospects for Reduced Oil Consumption in Canada. W. B. Friedenberg and A. J. Nixon. May 1980 (Price $3.00, 34 pages).

81-1 Crude Oil Supply and Demand: Major Issues and Alternate Scenarios. Douglas J. Haughey. July 1981 (Price $7.00, 158 pages).

81-2 Natural Gas Pricing in Canada: An Economic Analysis. Andrea J. Nixon. October 1981 (Price $5.00, 116 pages).

82-1 Potential for Reducing Oil Demand Through Conservation. Georgette Habib. September 1982 (Price $7.00, 47 pages).

83-1 Development Options for Maritime Coal. John A. Dawson. January 1983 (Price $7.50, 42 pages).

83-2 Development Options for Alberta and Saskatchewan Coal. Tricia Gibson. March 1983 (Price $7.50, 42 pages).

Discussion Papers

82-1 Significance of Interregional Feedbacks for Canadian and Regional Energy Policy Decisions. Gordon W. Douglas and James A. MacMillan. March 1982 (Price $2.00, 10 pages).

83-1 The Alberta New Oil Royalty Formula: 74-04-01 TO 82-12-31. Alan R. Webster. March 1983 (Price $6.00, 56 pages).

Proceedings

Markets for Canadian Uranium. Proceedings of a Seminar Held on October 25, 1979, Calgary, Alberta (Price $10.00, 89 pages) ISBN 0-920522-08-4.

Economic Potential for Alternative Transportation Fuels: Methanol, Ethanol, Propane, Liquified Coal, Compressed Natural Gas and Hydrogen. Proceedings of a Seminar Held on November 17, 1981, Calgary, Alberta. (Price $10.00, 83 pages) ISBN 0-920522-19-X.

World Oil Market Conference. Proceedings of a Conference Held on October 18, 1982, Calgary, Alberta. Edited by Shane S. Streifel (Price $50.00, 220 pages) ISBN 0-920522-25-4.

Annual Report

Annual Report of the Board of Directors for the Period April 1, 1981 to March 31, 1982. ISBN 0-920522-22-X.

POOR

QUALITY

ORIGINAL